REPORT

Ellensfield Coal Mine Project Greenhouse Gas Assessment

Prepared for

Vale

Vale Australia Pty Ltd
Level 9, NAB House
100 Creek Street Brisbane 4001

1 June 2009

42626093

URS

Project Manager:

Rob Storrs

Associate Environmental Scientist

Project Director:

Chris Pigott

Senior Principal

URS Australia Pty Ltd

Level 16, 240 Queen Street
Brisbane, QLD 4000
GPO Box 302, QLD 4001
Australia
T: 61 7 3243 2111
F: 61 7 3243 2199

Date:	1 June 2009
Reference:	42626093 GHG
Status:	Final

Table of Contents

Table of Contents

Introduction Section 1

The Ellensfield Coal Mine Project (ECMP) is a proposed underground coal mine development in the Bowen Basin coalfields in Central Queensland. The proposed mine is forecast to produce up to approximately 4.7 Million tonnes per annum (Mtpa) of export coking and thermal product coal over a projected mine life of approximately 20 years.

This greenhouse gas assessment presents an inventory of projected annual emissions of greenhouse gas, and the total emissions expressed as carbon dioxide equivalent for the ECMP over the life of the mine from fugitive coal seam gas emissions, combustion of gas and diesel, the use of electricity and the use of explosives.

To provide context, the project's greenhouse gas (GHG) emissions are also presented as a percentage of Queensland's and Australia's annual greenhouse gas emissions.

Section 2 Greenhouse Gas Emission Legislative Framework

2.1 International Policy

In 1997, the United Nations Framework Convention on Climate Change (UNFCCC) produced the Kyoto Protocol aimed at limiting the greenhouse gas emissions of countries that ratified the protocol. It entered into force in 2005. The protocol was designed to work by setting limits to individual mandatory greenhouse gas emission targets using that country's 1990 greenhouse gas emissions as the baseline.

The Kyoto Protocol sets out three "flexibility mechanisms" to allow greenhouse gas targets to be met:

- The Clean Development Mechanism;
- Joint Implementation; and
- International Emissions Trading.

These three mechanisms effectively allow greenhouse gas reductions to be made at the point where the marginal cost of that reduction is lowest. Essentially, an industrialised country sponsoring a greenhouse gas reduction project in a developing country can claim that reduction towards its Kyoto Protocol target and those greenhouse gas reductions can be traded.

Australia ratified the Kyoto Protocol in December 2007, and has committed to meeting its Kyoto Protocol target of 108 % of 1990 emissions by 2012.

2.2 Australian Policy

The Australian policy on climate change was released in July 2007 and is managed by the Department of Climate Change. It sets out the Commonwealth Government's focus on reducing emissions, encouraging the development of low emissions and emission reduction technology, climate change adaptation, and setting Australia's policies and response to climate change within a global context.

2.2.1 Garnaut Review

The Federal Government commissioned the Garnaut Climate Change Review as an independent study to examine the impacts, challenges and opportunities of climate change for Australia. The Review's Final Report was released on 30 September 2008. This review considered the potential impacts that climate change will have on Australia's environment and economy, and proposed medium to long-term policies and policy frameworks to improve the prospects for sustainable prosperity.

2.2.2 Carbon Pollution Reduction Scheme (CPRS)

In December 2008, the Commonwealth Government released its White Paper on the design of the Carbon Pollution Reduction Scheme (CPRS). The CPRS will comprise a cap on Australia's greenhouse gas emissions as well as implementing a carbon emissions trading scheme so that affected industries can purchase credits to reduce their GHG emissions.

At a minimum, the Government has committed to an unconditional 5% reduction below 2000 levels of GHG emissions by 2020. In the event that there is a global agreement and advanced economies take on commitments comparable to Australia, the Government has committed to reducing Australia's emissions by up to 15% below 2000 levels. The CPRS will cover stationary energy, transport, fugitive emissions, industrial processes, waste and forestry sectors, and all six greenhouse gases counted under the Kyoto Protocol from the time the scheme begins.

Under the CPRS, entities in covered industries that directly emit more than a specified threshold amount of GHGs will be required to surrender permits at the end of each compliance period to match their GHG emissions. If a covered entity fails to surrender sufficient permits, it will be subject to penalties. Vale will be required to obtain and surrender permits with respect to the covered GHG emissions from the ECMP. At the time of writing, the coal industry has been excluded from assistance as an Emissions Intensive Trade Exposed industry.

Draft legislation for the CPRS has been released by the Commonwealth Government. The Government proposes to commence the scheme on 1 July 2010.

2.2.3 National Greenhouse and Energy Reporting Act 2007 (NGER)

The NGER Act establishes a national framework for Australian corporations to report Scope 1 and Scope 2 (see Section 2.3) greenhouse gas emissions, reductions, removals and offsets, and energy consumption and production. It is designed to provide robust data as a foundation to the CPRS.

From 1 July 2008, corporations will be required to register and report if:

- they control facilities that emit 25 kilotonnes or more of greenhouse gas (CO_2 equivalent), or produce/consume 100 terajoules or more of energy; or
- their corporate group emits 125 kilotonnes or more greenhouse gas (CO_2 equivalent), or produces/consumes 500 terajoules or more of energy.

Lower thresholds for corporate groups will be phased in by 2010-2011. Companies must register by 31August, and report by 31 October, following the financial year in which they meet a threshold.

2.2.4 Energy Efficiency Opportunities (EEO)

The Energy Efficiency Opportunities (EEO) legislation came into effect in July 2006, and requires large energy users (over 0.5 PJ of energy consumption per year) to participate in the program. The objective of this program is to drive ongoing improvements in energy consumption amongst large users, and businesses are required to identify, evaluate and report publicly on cost effective energy savings opportunities.

EEO legislation is designed to lead to:

- Improved identification and uptake of cost-effective energy efficiency opportunities;
- Improved productivity and reduced greenhouse gas emissions; and
- Greater scrutiny of energy use by large energy consumers.

The EEO legislation will be incorporated into the National Framework for Energy Efficiency.

Vale is the sole proponent of the Ellensfield Coal Mine Project, which alone will trigger the requirements under the EEO. However, Vale is also part owner in a range of other projects within Australia. Therefore, as a large energy user, Vale is a mandatory participant in EEO. Consequently, the minimum requirements of the scheme need to be met by the Project. As the program's Assessment Framework takes a whole of business approach to assessing energy use and energy savings opportunities, the framework involves corporations looking at the many factors influencing energy use, including leadership, management and policy; the accuracy and quality of data and analysis; the skills and perspectives of a wide range of people; decision making; and communicating outcomes. Participants are expected to meet minimum requirements in each of these areas.

2.3 State Policy and Initiatives

In October 2007, the Queensland Government created the Office of Climate Change in order to lead an effective climate change response. The strategy adopted is ClimateSmart 2050.

ClimateSmart 2050 aims at reducing greenhouse gas emissions by 60 % from 2000 levels by 2050 in line with the national target by building initiatives into the Queensland Government's 2000 Energy Policy. Its initiatives include:

- the introduction of a Smart Energy Savings Program, which target large energy users and require them to undertake energy efficiency audits and implement energy savings measures that have a three year or less payback period;
- the Queensland Future Growth Fund for development of clean coal technologies; and
- Changes to the Queensland Gas Scheme which will oblige major industries to source 18 % of all power from Queensland based gas-fired generation.

3.1 Accounting and Reporting Principles

This inventory follows the accounting and reporting principals detailed in the Greenhouse Gas Protocol, which was first established in 1998 to develop internationally accepted standards for this purpose.

The main principles are as follows:

- Relevance: The inventory must contain the information that both internal and external users need for their decision making.
- Completeness: All relevant emissions sources within the inventory boundary need to be accounted for so that a comprehensive and meaningful inventory is complied.
- Consistency: The consistent application of accounting approaches, inventory boundary and calculation methodologies is essential to producing comparable GHG emissions over time.
- Transparency: Information needs to be archived in a way that enables reviewers and verifiers to attest to its credibility. All parameter, values and methodologies used are accessible and presented within the inventory.
- Accuracy: Data should be sufficiently precise to enable intended users to make decisions with reasonable assurance that the reported information is credible.

3.2 Inventory Boundaries

In preparing a Greenhouse Gas Assessment, there are two forms of boundaries to be specified: organisational boundaries and operational boundaries.

Vale is the sole owner of the ECMP. The organisational boundary is delineated by the physical Mine Area comprising the three Mining Leases (MLa 70393, MLa 70395, and MLa 7394) and includes all the greenhouse gas emissions controlled or influenced by the project.

The operational boundary for the greenhouse gas assessment includes both direct and indirect emissions from the project.

The Greenhouse Gas Protocol further defines direct and indirect emissions through the concept of emission “scopes”.

- Scope 1: Direct (or point-source) greenhouse gas emissions. Direct greenhouse gas emissions occur from sources that are owned or controlled by a company. For example:
  - Emissions from combustion in owned or controlled boilers, furnaces, vehicles, etc.;
  - Emissions from on-site power generators; and
  - Coal Seam Gas released to atmosphere.
- Scope 2: Indirect greenhouse gas emissions. This accounts for greenhouse gas emissions from the generation of electricity (or steam or heating/cooling) purchased and consumed by the company. Purchased electricity is defined as electricity that is purchased or otherwise brought into the organisational boundary of the company. Scope 2 emissions physically occur at the facility where electricity is generated

but they are allocated to the organisation that owns or controls the plant or equipment where the electricity is consumed.

- Scope 3: Indirect greenhouse gas emissions. This is an optional reporting class that accounts for all other indirect greenhouse gas emissions resulting from a company's activities, but occurring from sources not owned or controlled by the company. Examples include extraction and production of purchased materials; transportation of purchased fuels; and use of sold products and services.

3.3 Calculation Approach

The greenhouse gas emission inventory for the Project is based on the methodology detailed in the Greenhouse Gas Protocol (the Protocol), and the relevant emission factors in the National Greenhouse Accounts (NGA) Factors, the *Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006 – Energy (Fugitive Fuel Emissions)* and the relevant Intergovernmental Panel of Climate Change (IPCC) Good Practice Guidance.

A spreadsheet model has been specifically developed for the Project and uses the data sources and emission factors detailed below in order to calculate project emissions for every year of construction and operation, according to the Protocol using the methodology detailed in the NGA Factors.

There are several greenhouse gases including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). In order to simplify inventory accounting, a unit called carbon dioxide equivalents (CO_2-e) is used. This accounts for the various global warming potentials of non-CO_2 gases. The global warming potential is a measure of the amount of infrared radiation captured by a gas in comparison to an equivalent mass of CO_2, over a fixed lifetime. GHG inventories in this report are expressed as mass of CO_2-e released, following this convention.

3.3.1 Activity Data Sources

Data from the following sources have been utilised in the formation of the inventory:

- Activity data (electricity and diesel use) used to assess Scope 2 and some Scope 1 emissions was provided in the spreadsheet "Ellensfield Overall Load Estimates Rev A2 th.xls" and is broken down into yearly consumption from 2007 through 2017. This included:
  - Estimated electricity consumption in MWh; and
  - Estimated diesel consumption in litres.
- Activity data used to assess most Scope 1 emissions based on "Ellensfield Schedule Summary Rev C4.xls", provided by Vale in April 2008, and is broken down into yearly production from 2010 through 2030. This included:
  - Estimated Run of Mine (ROM) coal for the mine area as a whole for each year of operation of the mine;
  - Estimated Product Coal (tonnes) for each year of operation of the mine; and
- Activity data used to assess Scope 1 emissions from use of explosives based on "Blasting Details.xls", provided September 2008.

3.3.2 Emission Factors

Direct measurement of GHG at the emission source can give the most accurate and precise assessment of GHG emissions. This is typically not feasible at a mine because of the cost involved, the disruption to production involved, and the typically large number of trucks and plant equipment used. Emission factors remove the need for site specific testing of emissions. They are a factor expressed as the amount of GHG emissions per unit of activity, which can be used to determine inventories for a site. This is more feasible than testing each source individually, and it is one of the few ways that inventories for proposed sites can be calculated.

Emission factors can be determined from various sources, for example, the Department of Climate Change; from site-specific information or from operational details obtained from similar emission sources. The majority of the emission factors used in this report have been sourced from the Department of Climate Change NGA Factors Workbook, 2008 as indicated in Table 3-1 below.

Table 3-1 Emission Factors used in the formation of the Project GHG Inventory

Emission Source	Units	Emission Factor	Source
Scope 1 Emissions			
Fugitive open cut coal mine emissions	kg CO_2-e/ t ROM	17.1	NGA Factors. Table 6 (production of coal, fugitive emissions)
Combustion emission factor diesel	t CO_2-e/ kL	2.7	NGA Factors. Table 4, (fuel combustion for transport)
Combustion emission factor coal seam gas	kg CO_2-e/ GJ	51.1	NGA Factors. Table 2, (consumption of natural gas)
Explosives - ANFO	t CO_2 / t explosive used	0.17	NGA Factors (released January 2008). Table 4 (explosive use)
Scope 2 Emissions			
Electricity Consumption (QLD)	kg CO_2-e/ kWh	0.91	NGA Factors. Table 5 (consumption of purchased electricity)
Scope 3 Emissions			
Black coal used for electricity - QLD	kg CO_2-e/ GJ	91.1	NGA Factors. Table 1 (fuel combustion factors, stationary energy)
Black coal used for coking	kg CO_2-e/ GJ	90.2	NGA Factors. Table 1 (fuel combustion factors, stationary energy)
Electricity Consumption	kg CO_2-e/ kWh	0.13	NGA Factors. Table 5 (EF from consumption of purchased electricity)
Diesel Consumption	t CO_2-e/ kL	0.2	NGA factors. Table 4 (EF for Diesel (Automotive Diesel Oil))

3.3.3 Materiality

Materiality is a concept used in accounting and auditing to minimise time spent verifying amounts and figures that do not impact a company's accounts or inventory in a material way. The exact materiality threshold that is used in GHG emissions accounting and auditing is subjective and dependant on the context of the site and the features of the inventory. Depending on the context, the materiality threshold can be expressed as a percentage of a company's total inventory, a specific amount of GHG emissions, or a combination of both.

All emissions that are found within the boundary are included in the inventory unless they are excluded on materiality grounds. Information is considered to be material if, by its inclusion or exclusion it can be seen to influence any decisions or actions taken by users. A material discrepancy is an error (for example, from an oversight, omission or miscalculation) that results in a reported quantity or statement being significantly different to the true value or meaning.

Within this report emissions are assumed to be immaterial if they are likely to account for less than 5% of the overall emissions profile. This materiality threshold has been chosen on the basis of the author's experience of open-cut coal mine GHG inventories. The following emissions are not included in the inventory on the basis of materiality:

- Consumption of unleaded fuel (ULP) or LPG in site vehicles. Most site vehicles run on diesel fuel, which is included in the inventory. Only small vehicles such as cars belonging to site personnel will consume unleaded fuel and are typically immaterial; and
- The inventory does not consider emissions arising from land use, land use change and forestry such as rehabilitation and clearing. The mine is predominately underground; the clearing of the surface area planned to be disturbed is not expected to be a significant GHG emission source.

3.3.4 Aggregation

Aggregation refers to the combining of several inventories, typically of different sites or operations, into an overall inventory. This chapter is specific to the ECMP site inventory and does not contain an aggregated inventory of all Vale's greenhouse gas emissions.

Scope 1 and Scope 2 Emissions

The greenhouse gas Scope 1 and Scope 2 emission sources from the Project included in this inventory are:

- Fugitive emissions of coal seam gas (CSG) from the mining of coal (Scope 1);
- Combustion emissions from burning coal seam gas for power generation and in the flare (Scope 1);
- Fuel consumption in vehicles (Scope 1);
- Use of explosives (Scope 1); and
- Electricity consumption (Scope 2).

The GHG emissions have been estimated for construction and the operation of the Project, which is for 21 years beginning in 2010.

4.1 Fugitive Emissions

Fugitive emissions from coal mines relate to Coal Seam Gas (CSG), the majority of which is methane with the remainder being CO_2. Default fugitive CSG factors quote a single emission rate for either all Queensland open cut coal mines or Queensland gassy underground coal mines, or all non-gassy underground coal mines. Since CSG can contribute up to approximately 50 % of total greenhouse gas emissions from a mine, it is important that the emission factor be robust and based on in-situ testing of coal seam methane content.

Gas content testing by GeoGas Pty Ltd of nine of a planned fifteen surface boreholes have been completed to date for the ECMP. Of the nine boreholes drilled for gas testing, the gas content has been measured in the targeted Leichhardt seam. The GeoGas report dated April 2008 found across the mine plan area that the measured gas content at 40 % seam ash content varies from 0.6 to 13.9m^3/t. There is a general increase in gas content with depth, and chromatography analysis undertaken during gas content testing indicates the composition to be predominately methane (CH_4) (> 98% methane).

It is very difficult to capture CSG from open cut coal mines, however due to the nature of an underground coal mine, capture of significant amounts of the CSG becomes possible. As methane has a significantly higher global warming potential than CO_2, flaring of the methane becomes a desired option as this converts the methane (CH_4) to CO_2 and water, with an overall significantly lower t CO_2-e/t raw coal.

For this assessment, URS has assumed that 100 % of the gas content released from the coal is methane, and 75 % of the gas released from the underground mine will be captured. The gas will be sent to an 8 MW capacity power plant, with excess gas flared. Gas capture will comprise both pre-drainage and post-mining methane drainage. The remainder 25 % from the underground mine and all of the gas content from the coal mined in the box cut will be released to atmosphere as this gas cannot be economically captured. URS has also assumed that there is a linear increase in gas content as the seam becomes deeper from Year 1 to Year 5 of production. The assumed methane emissions from ROM coal are provided in Table 4-1.

Table 4-1 Linear Increase in Gas Content from ROM Coal

Gas Content Unit	Year 1 of Production	Year 2 of Production	Year 3 of Production	Year 4 of Production	Year 5 of Production and thereafter
m^3 CH_4/tonne raw coal	2.4	4.8	7.2	9.6	12
kg CH_4/tonne raw coal[1]	1.6	3.2	4.8	6.4	8.0

[1] Ideal gas law assuming an ambient pressure of 1 atm and temperature of 298 K

The ideal gas law was used to convert m^3 of CH_4 to kg of CH_4 for inventory calculations. Assuming an ambient pressure of 1 atm and temperature of 298 K, 2.4 m^3 CH_4/tonne ROM is equivalent to 1.6 kg (or 0.0016 tCH_4)/tonne ROM. To convert this to t CO_2-e/tonne ROM to reflect the flaring process, the following chemical equation was used: $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$.

URS has relied upon the GeoGAS report for site specific coal seam gas data used in this inventory. URS is not able to comment on the representativeness of the sampling and measurement program.

4.1.1 Spontaneous Combustion of Coal

Some articles (Williams 1998 and Day 2008) have suggested that oxidation of coal and carbonaceous wastes, such as uneconomic thin seams disposed of in overburden stockpiles, may be a source of GHG emissions. This is a result of spontaneous combustion of stockpiles, which has a known GHG source and known management regime. This source has not been considered in the Project inventory because:

- there is no accepted methodology, at either an international or Australian level, for estimating GHG emissions from spontaneous combustion;
- there is extremely large degree of variability between mines that experience spontaneous combustion and those that do not; and
- the Project will implement management techniques according to the Australian Coal Association Research Program (ACARP) guidelines to further minimise the potential occurrence of spontaneous combustion.

4.2 Combustion of Coal Seam Gas in Power Plant

An 8 MW capacity gas-fired power plant is proposed for the site. This will serve to generate power for on-site use for mining equipment and infrastructure, replacing some of the electricity that would otherwise be supplied from the electricity grid. Excess gas will be burnt in the flare.

Preliminary calculations have been based on the following assumptions:

- Gas turbine efficiency of 35%;
- CSG consumption is approximately 2.3 million cubic meters per year per MW;
- The captured CSG that is not used to fuel the power plant will be flared;
- Power plant will operate for all hours of the year;

- Power generated on-site will displace electricity that is purchased from the grid;
- The power plant is configured as 8 x 1 MW units.

4.3 Diesel Combustion by Vehicles

Diesel is consumed by vehicles and stationary energy sources (for example generators) at mine sites. The projected consumption of diesel for the project including major equipment and ancillary equipment was provided for each year of the life of the mine up to Year 8 (2017). It was assumed that diesel consumption in Years 9 to 21 inclusive were equivalent to those of Year 8, as the travel distance for haul trucks is the same as for Year 8 and mine production rate is similar for these years.

The GHG emissions associated with diesel consumption for each year of operation have an average of 6,210 t CO_2-e annually.

Combustion of unleaded petrol is not included as part of the GHG inventory as the emissions released from the vehicles that consume unleaded petrol, based on experience, is likely to be an immaterial component of the inventory. GHG emissions arising from combustion of unleaded petrol are therefore considered immaterial in relation to the Project.

4.4 Explosives

Explosives are used by coal mines to loosen overburden material and to break apart the coal seam for ease of loading. Greenhouse gas emissions are generated from the use of explosives at the site due to release of combustion pollutants such as CO_2 and nitrous oxide. The type of explosive to be used on this site is ammonium nitrate-fuel oil (ANFO) mixture.

The Project will use ANFO for the box cut only. The projected use of explosives for each month during construction work on the box cut for 18 months was provided.

The greenhouse gas emissions from explosives for two years of construction will be 816 and 408 t CO_2-e per year, respectively.

4.5 Power Consumption

Underground coal mines consume significant amounts of electricity to power longwall mining equipment, conveyers, pumps, compressors, motors, coal handling and preparation plants and offices. The predicted electricity consumption in MWh was provided as an aggregate for the entire site operations by year up to Year 8 (2017). It was assumed that electricity consumption in Years 9 to 21 inclusive were equivalent to those of Year 8.

The use of electricity is expected to increase from the start of construction of the box cut, increasing with mine operations until stabilising from 2017. The GHG emissions associated with electricity consumption for each year of operation have an average of 174,168 t CO_2-e annually.

Section 5 Scope 3 Emissions

Scope 3 emissions are defined in the Greenhouse Gas Protocol as an optional reporting class that accounts for GHG emissions resulting from a company's activities, but occurring from sources not owned or controlled by the company. Examples include extraction and production of purchased materials, transportation of purchased fuels, and employee business travel and commuting.

Scope 3 emissions are not routinely reported by companies because:

- Emissions are difficult to estimate accurately;
- The company does not have effective control of the emissions sources; and
- A company's Scope 3 emissions will be reported elsewhere by a second company as their Scope 1 emissions. As an example, emissions from coal sold to a power station for electricity generation will be reported by the power station as one of their Scope 1 emissions.

The overwhelming majority of Scope 3 emissions from the Project are due to the end use of the coal in electricity generation or steel production. Other Scope 3 emissions from the Project are:

- Emissions from transport of materials and infrastructure to the mine;
- Emissions from extraction and processing of diesel consumed by the Project;
- Emissions from waste to landfill;
- Emissions from employee travel;
- Emissions from the transportation of coal from the mine to the point of use; and
- Emissions from the generation and transmission of electricity used by the Project.

Published emission factors have been used in calculating the Scope 3 emissions.

Due to limitations in data availability, Scope 3 emissions for the following sources have not been included in the inventory:

- Transportation of materials and infrastructure to the mine;
- Waste to landfill;
- Employee travel; and
- Transportation of coal from the mine to the point of use.

End-Use

The impact of the eventual end-use of the coal (thermal and coking) in electricity and steel production is much greater than the greenhouse gas emissions due to mining and transportation and contributes to over 99% of the of the Scope 3 emissions. Not all known Scope 3 emissions are included in this inventory; however, end use emissions are expected to be the overwhelming majority of all Scope 3 emissions.

Scope 1, 2 and Emissions Summary

The following table summarises the activity data used in the GHG Emissions Inventory.

Table 6-1 Summary of Annual Activity Data used in the GHG Emissions Inventory

Activity Data	Minimum	Maximum	Average	Life of Mine
ROM (tpa)	197,263	5,838,955	4,495,927	94,414,463
Coking Coal (tpa)	88,894	2,631,267	2,026,044	42,546,934
Thermal Coal (tpa)	80,751	2,390,235	1,940,453	38,649,505
Electricity (MWh)	12,845	210,000	183,277	4,032,095
Diesel (L)	575,000	6,000,000	2,310,417	55,450,000
ANFO (t) (only used during construction)	0	4,800	3,600	7,200

The following table summarises the Scope 1, 2 and 3 emissions for the project. The annual emissions from the project are presented as well as the total GHG emissions over the 21-year mine life.

Section 6 Scope 1, 2 and Emissions Summary

Table 6-2 Greenhouse Gas Emissions for the Project

Scope	Source	Minimum Emissions ($t\ CO_2$-e / yr)	Maximum Emissions ($t\ CO_2$-e / yr)	Average Emissions ($t\ CO_2$-e / yr)	Life of Mine Emissions ($t\ CO_2$-e)
1	Fugitive emissions	6,613	244,675	182,499	3,832,488
1	Emissions from Flare	-	62,573	41,868	879,222
1	Emissions from Power Plant	-	36,978	32,576	684,097
1	Diesel combustion	1,553	16,200	6,238	149,715
1	Explosives	-	816	408	1,224
	Total Scope 1[I]	1,553	350,436	231,114	5,546,746
2	Purchased electricity	-	159,214	101,911	2,445,871
	Total Scope 1 and Scope 2[II]	1,553	477,763	333,026	7,992,617
3	End-Use for Coking Coal	240,548	7,120,208	5,482,476	115,132,003
3	End-Use for Thermal Coal	157,428	4,659,858	3,588,036	75,348,755
3	Electricity Generation and Transmission	-	22,745	14,559	349,410
3	Extraction and processing of Diesel	115	1,200	462	11,090
	Total Scope 3[III]	115	11,798,715	7,951,719	190,841,258
	Total Scope 1 and Scope 2 and Scope 3[IV]	1,668	12,276,478	8,284,745	198,833,875

[I] This row indicates the minimum, maximum, average and life of mine emissions of all the totalled Scope 1 emissions and hence will not equal the total of the Scope 1 emissions included in this table.

[II] This row indicates the minimum, maximum, average and life of mine emissions of all the totalled Scope 1 and 2 emissions and hence will not equal the total of the Scope 1 and 2 emissions included in this table.

[III] This row indicates the minimum, maximum, average and life of mine emissions of all the totalled Scope 3 emissions and hence will not equal the total of the Scope 3 emissions included in this table.

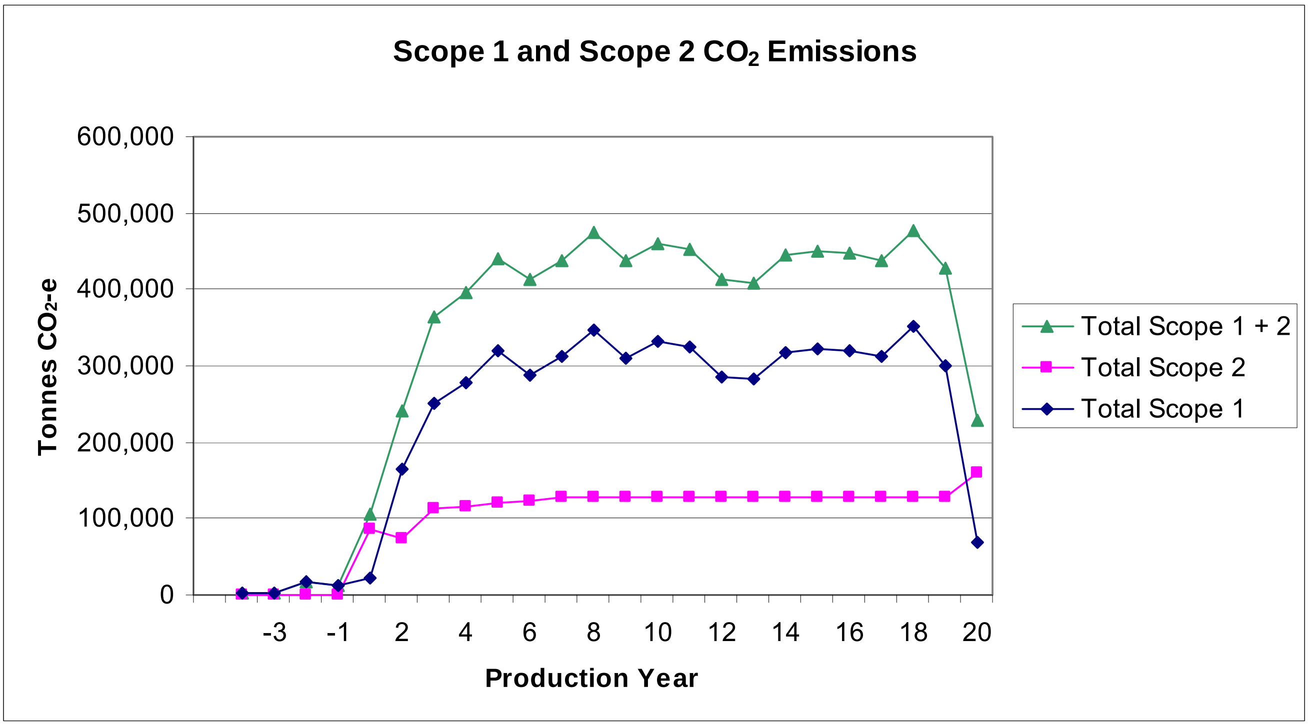
[IV] This row indicates the minimum, maximum, average and life of mine emissions of all the totalled scope 1, 2 and 3 emissions and hence will not equal the total of the scope 1, 2 and 3 emissions included in this table.

The GHG emissions presented are based on current knowledge about the mine operations, GHG emissions from coal seam gas content, diesel, electricity consumption, and the amount of gas captured. These emissions may in fact change over the life of the mine due to technology improvements.

6.1 Scope 1 and Scope 2 Emissions

Figure 6-1 shows the estimated GHG emissions for the Scope 1 and Scope 2 emissions throughout the life of the mine.

Figure 6-1 Total of Scope 1 and Scope 2 GHG emissions (t CO_2-e)



Analysis of the annual GHG inventory for all Scope 1 and Scope 2 emissions shows the GHG emissions are forecast to sharply increase in Years 1 and 2 in line with commencement of coal production. From Year 3 onwards GHG emissions are forecast to remain approximately steady with small fluctuations with the largest quantities of GHG emissions in Years 9, 11 and 19. These peaks correspond with the years of higher run of mine coal production, and the corresponding CSG liberated due to production.

The mine will be obliged to report under the NGER Act given that emissions for the Project's Scope 1 and 2 emissions will exceed the 25 kilotonne threshold from the first year of operation.

The GHG emissions presented are based on current knowledge about the mine operations and GHG emissions from coal seam gas content, diesel, electricity consumption, and may in fact change over the life of the mine due to technology improvements. Pre-drainage of the coal seam will also alter the yearly profile of GHG emissions but not the Life of Mine emissions.

6.1.1 Performance Measures

The performance of the greenhouse gas emissions efficiency is measured as emissions intensity, as defined by the Greenhouse Gas Protocol. Emissions intensity is defined as tonnes CO_2-e/ tonnes product coal.

The emissions intensity based on Scope 1 and 2 for the Ellensfield Coal Mine operation years ranges from 0.06 to 0.3 t CO_2-e/t product coal, and has an average of 0.11 t CO_2-e/t product coal. The 18 months of construction (2009 and 2010) prior to the operational phase of the Project are not included in this comparison as no coal is produced and therefore no performance assessment can be conducted.

6.2 Life of Mine Emissions

The Project's full fuel cycle GHG emissions for the life of the mine have been calculated by the addition of the Scope 1, 2 and 3 emissions, and total 198.8 Mt CO_2-e. The summary of Life of Mine Emissions is based on the assumption that the duration of the mine's life will be 21 years, based on the economically feasible extraction of coal. Therefore it is fundamentally an economic variable and subject to change with the coal market.

The overwhelming majority of full fuel cycle emissions from the Project are associated with emissions from end-use for electricity and steel production. The forecast proportion of emissions associated with end-use is 96%. Scope 1 and 2 emissions contribute 4% over the life of the mine on a full-fuel cycle basis.

7.1 Uncertainty Analysis Background

A measure of the uncertainty within the inventory is a standard part of a GHG inventory as indicated by the GHG Protocol. Uncertainties associated with the GHG inventory are either related to scientific uncertainty or estimation uncertainty. Analysing and quantifying scientific uncertainty is extremely problematic as it often involves for example estimating uncertainty in the global warming potential values and as a consequence, an estimate of scientific uncertainty is beyond the capacity of this inventory. Estimation uncertainty can be classified further into two types: model uncertainty and parameter uncertainty. Model uncertainty refers to the uncertainty associated with mathematical equations used to calculate the emissions. This is also beyond the scope of the Project inventory.

Parameter uncertainties within this inventory can be divided into two parts: uncertainty relating to activity data and uncertainty relating to emission factors. Activity uncertainties relate to measured quantities, such as production, consumption, monitored data etc. Emission factor uncertainty considers the conversion from measured activities to GHG emissions.

The method used to calculate uncertainty is based on the IPCC guidelines, namely the Error Propagation Function analysis. The activity and emission factor uncertainties are defined using qualitative techniques, and then values are assigned to each source on the following basis:

- Low uncertainty: 0 – 5%
- Medium uncertainty: 6 – 20%
- High uncertainty: >21%

The Error Propagation Function analysis is then used to determine the level of uncertainty of each source contributes to the overall uncertainty of the inventory, weighted by the percent of contribution of each source towards the total inventory.

7.2 Inventory Uncertainty Analysis

Table 7-1 shows the results of the uncertainty analysis used to define the uncertainty within annual GHG emissions. Production year 19 was selected as the base year for this analysis, as this is the year with the highest GHG emission.

Section 7 Inventory Uncertainty Analysis

Table 7-1 Scope 1 and 2 Emissions Uncertainty for the Project Year 19

Scope	Source of Emissions	Tonnes CO_2e Emitted	Contribution to Total Emissions (%)	Activity Uncertainty (±%)	Emission Factor Uncertainty (±%)	Contribution to Overall Uncertainty (±%)	Total Uncertainty t CO_2-e
1	Fugitive Emissions	244,675	51%	15%	40%	22%	±104,525
1	Emissions from Flare	62,573	13%	15%	40%	6%	±26,731
1	Emissions from Power Plant	36,978	8%	15%	40%	3%	±15,797
1	Diesel Consumption	6,210	1%	15%	10%	0.2%	±1,120
1	Explosives-ANFO [(1)]	0	0%	10%	20%	0%	±0
2	Electricity Consumption	127,327	27%	10%	10%	4%	±18,007
	Total	**477,763**	**100%**	**N/A**	**N/A**	**13%**	**±61,654**

[(1)] Explosives were only used in the first two years when constructing the box cut.

Given that operations at the mine have not commenced, uncertainties for all activity levels have been estimated by URS on the basis of past experience and are considered to have a low or medium activity uncertainty.

With the exception of fugitive emissions, all emissions factors have been sourced from the National Greenhouse Accounts factors workbook, which are nationally derived emission factors. Therefore, the uncertainty associated with emissions factors is considered to be low. The emission factor for fugitive emissions is considered to be high due to the high standard deviation for the gas content stated in the GeoGAS report. Despite this, there is strong evidence that the overall amount of coal seam gas in the Leichhardt seams is low and significantly lower than default emission factors would suggest.

The analysis based on Year 19 of the mine's operation indicates that the overall uncertainty within the inventory is ±13%, with the majority of the uncertainty contribution due to fugitive emissions. The absolute uncertainty expressed as t CO_2-e for one year of the mine's operation is estimated to be 61,654 t CO_2-e.

Comparison with Australian Emissions — Section 8

8.1 Australian Emissions

The National Greenhouse Gas Inventory (Department of Climate Change, 2008) is the latest available national account of Australia's GHG emissions. The National Greenhouse Gas Inventory has been prepared in accordance with the Revised 1996 and 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The IPCC guidance defines six sectors for reporting greenhouse gas emissions:

1) Energy (including coal mining);
2) Industrial Processes;
3) Solvent and Other Product Use;
4) Agriculture;
5) Land Use, Land Use Change and Forestry; and
6) Waste.

Australia's net greenhouse gas emissions across all sectors totalled 576 Mt CO_2-e in 2006, with the energy sector being the largest emitter at 400.9 Mt CO_2-e. Emissions from coal-mining sources are captured under the energy category of the IPCC methodology. Approximately 34.5 Mt of energy sector emissions were attributable to fugitive emissions, representing 6.0% of national emissions.

Table 8-1 shows total annual Scope 1 and 2 emissions at different stages of the life of the mine as a percentage of Australian total and energy sector emissions taken from the National Greenhouse Gas Inventory 2006.

Table 8-1 Comparison of Australian and Project GHG emissions

Year of Operation	Percent of Australian Energy Sector Total	Percent of Australian Total
Minimum GHG emissions (Year 1)	0.003%	0.002%
Peak GHG emissions (Year 19)	0.12%	0.08%
Average GHG emissions (Year 4)	0.08%	0.06%

8.2 Queensland Emissions

Table 8-2 shows total annual Scope 1 and 2 emissions at different stages of the life of the mine as a percentage of Queensland total (170.9 Mt) and Queensland energy sector (96 Mt) emissions taken from the National Greenhouse Gas Inventory 2006.

Section 8 Comparison with Australian Emissions

Table 8-2 Comparison of Queensland and Project GHG emissions

Year of Operation	Percent of Queensland Energy Sector	Percent of Queensland Total
Minimum GHG emissions (Year 1)	0.013%	0.008%
Peak GHG emissions (Year 19)	0.50%	0.28%
Average GHG missions (Year 4)	0.35%	0.19%

When viewed in an Australian or Queensland context, the Scope 1 and 2 emissions from the Project are not considered materially relevant given the project emissions are 0.5% of the Queensland energy sector at peak emissions.

8.2.1 Impact of the Project on Queensland Emissions Targets

The Queensland government has proposed to reduce greenhouse gas emissions by 60 % by 2050 based on 2000 levels in line with the national target. This equates to a reduction of approximately 98 Mt CO_2-e.

In the years of peak greenhouse gas emissions, Scope 1 and 2 emissions from the mine will be 0.48 Mt CO_2-e. The Scope 1 and 2 emissions in peak years will be equal to 0.28 % of the state inventory. Project emissions are therefore unlikely to have a significant impact on Queensland government emissions targets.

Greenhouse Gas Reduction Measures

9.1 Carbon Pollution Reduction Scheme

The details of the proposed Carbon Pollution Reduction Scheme (CPRS) are explained in Section 2.2. The scheme requires significant emitters, defined as those emitting more than 25,000 t CO_2-e per year as Scope 1 emissions, to acquire permits for every tonne of greenhouse gas emitted. Those emitting more than 25,000 t CO_2-e per year of Scope 1 emissions need to acquire a 'carbon pollution permit' for every tonne of greenhouse gas they emit.

At the end of each year, each liable firm would need to surrender a 'carbon pollution permit' for every tonne of emissions produced in that year. Firms will compete to purchase the number of 'carbon pollution permits' that they require to meet their annual liability.

The Project will be affected as its total Scope 1 emissions are above the 25,000 t CO_2-e threshold (average emissions of 333,026 t CO_2-e per year), and therefore will need to participate in the scheme. Since to date coal mines are not eligible for assistance under the Government's emissions-intensive trade-exposed industry assistance package, the project will need to purchase and surrender permits for its Scope 1 emissions.

9.2 Electrical Efficiency

The project will be a significant consumer of electricity. It is normal operating procedure to maximise electrical efficiency due to the business requirements to minimise costs. The following activities are normally undertaken by mining companies to maximise electrical efficiency and the Project will similarly undertake these measures, which are typical of best practice management at coal mines. The Project will implement the following practices:

- Regular monitoring of electrical load and investigation whenever the load falls outside optimal parameters.
- A regular program of coal shearer inspection and repair. Poorly maintained shearers reduce the efficiency of the longwall, increasing electricity required to operate it per tonne of coal produced.
- Undertaking 6-monthly electrical calibration checks on machinery, and as per the manufacturers instructions.
- Use of high efficiency electrical motors throughout the mine site.
- Use of variable speed drive pumps with high-efficiency linings at the coal handling and preparation plant.
- Regular monitoring of the compressed air circuit so that leaks are repaired in a timely manner, as this maximises the operating efficiency of the compressor.
- Maintaining light fittings to maximise light delivery.
- Installing light-sensitive switches on haul road lights so that lights do not operate during the day.

In addition to these measures, Vale will need to participate in the Energy Efficiency Opportunities program which encourages companies to identify and implement energy saving measures. This will result in ongoing improvements and new opportunities to improve electrical efficiency at the site.

9.3 Diesel Efficiency

Diesel consumption in an underground mine is usually limited, due to the quality of air emissions from the use of diesel, and the difficulty in ventilating the mine of those emissions. The Project diesel consumption will be limited to personnel carriers (transporting crews throughout the mine), haul truck for product coal and rejects, and some other special purpose vehicles, namely a road grader.

The following activities are normally undertaken by mining companies to minimise diesel consumption and the Project will similarly undertake these measures, which are typical of best practice management. The Project will implement the following practices:

- Roads will be compacted to reduce rolling resistance;
- Purchase fuel efficient vehicles and equipment;
- Maintain vehicles and equipment as per the manufacturers specifications;
- Monitor diesel consumption across the site; and
- Monitor diesel consumption per kilometre travelled for each vehicle.

9.4 Fugitive emissions

The Project will capture and combust as much as practical (currently estimated at 75%) of the coal seam gas emissions from the underground mine. The captured gas will be used for on-site power generation (8 MW) with the remainder to be flared. This will significantly reduce the greenhouse gas equivalent emissions given that the methane will be converted to carbon dioxide, and carbon dioxide has significantly less global warming potential than methane. The capture and flaring of the CSG is possible as the project is an underground mine.

The National Greenhouse Account gives emission factors for fugitive coal seam gas emissions from Queensland underground mines, which can be used to estimate emissions in the absence of any on-site measurements of coal seam gas. The default emission factor is 305.3 kg CO_2-e per tonne of ROM coal mined.

The Project has conducted a drilling program to measure directly on-site coal seam gas contents across proposed seams. This program identified the coal seam gas content to be significantly lower than the default factor. As described in Section 4.1 above:

- the measured gas content at seam ash varies from 0.6 to 13.9 m^3/t; and
- the composition is predominately methane (CH_4).

Given the assumptions of a gas content of 12 m^3/t of 100% methane, and that 75% of the underground mine will be captured and flared or combusted for power generation, an estimated 40 kg CO_2-e per tonne of ROM coal mined will be released. This is well below the default emission factor in the National Greenhouse Accounts of 305.3 kg CO_2-e/t ROM coal mined.

Significant amounts of methane are released in the mine ventilation air. This is typically less than 1% methane which is costly to capture and treat with current technologies. Further discussion of the possible treatment of mine ventilation air is included in Section 9.5.

9.5 Future Alternatives

Four alternatives have been identified for future consideration that could reduce the Project's greenhouse gas emissions:

1) Installation of an 8 MW to 20 MW power plant on-site with flaring of remaining captured gas;

2) Diversion of all captured fugitive emissions to a pipeline for usage off-site;

3) Treatment of ventilation air; and

4) Enhanced methane recovery from post-mining (goaf).

While these alternatives are not included in the scope of the Project being proposed, these are options being examined by Vale for future potential implementation. The following sections discuss each and the potential greenhouse gas reductions achievable if they were to be implemented.

9.5.1 Installation of a 20 MW on-site power plant or no power plant

The Project has investigated the use of a higher capacity (20 MW) power plant, or alternatively no power plant to be installed on site. As for the case presented in Section 6, any excess gas that is captured and cannot be used in the power plant would be sent to the flare, and power generated would offset the purchase of electricity from the grid.

As for the base case presented in Section 4.2, the 20 MW power plant (comprising 20 x 1 MW units) will operate continuously and will displace electricity that is purchased from the grid for site requirements. For the early years of the Project, there is insufficient gas supply to provide 20 MW of generation capacity which has been accounted for in the assessment.

The estimated volume of CSG that will be captured per year is determined from the amount of coal mined each year, and thus varies slightly over the life of the mine. The power generation capacity is restricted by the amount of gas available for combustion, hence for some years the 20 MW power plant scenario would operate at less than full capacity. This equipment availability has been taken into account in the greenhouse gas emissions estimations. Table 9-1 compares the average annual emissions from the proposed Project with the results of the preliminary calculations of these two alternatives (20 MW power plant or no power plant).

Table 9-1 Comparison of Average Annual CO_2-e Emissions from the Proposed Project with the Inclusion of 20 MW Power Plant or no Power Plant

Scope	Source	Proposed Project	20 MW Power Plant		No Power Plant	
			Estimated emissions	Difference from base case	Estimated emissions	Difference from base case
1	Fugitive emissions	182,499	182,499	-	182,499	-
1	Emissions from Flare	41,868	3,526	-92%	71,423	71%
1	Emissions from Power Plant	32,576	74,837	130%	0	-100%
1	Diesel combustion	6,238	6,238	-	6,238	-
1	Explosives	408	408	-	408	-
	Total Scope 1 [a]	231,114	74,837	-68%	228,472	-1.1%
2	Purchased electricity	101,911	0	-100%	152,884	50%
	Total Scope 1 and Scope 2 [a]	333,026	265,375	-20%	381,355	15%
3	End-Use for Coking Coal	5,482,476	5,482,476	-	5,482,476	-
3	End-Use for Thermal Coal	3,588,036	3,588,036	-	3,588,036	-
3	Electricity Generation and Transmission	14,559	5,448	-63%	21,841	50%
3	Extraction and processing of Diesel	462	462	-	462	-
	Total Scope 3 [a]	7,951,719	7,942,609	-0.1%	7,959,001	0.1%
	Total Scope 1 and Scope 2 and Scope 3 [a]	8,284,745	8,207,984	-0.9%	8,340,356	0.7%

[a] Totals for each Scope have been calculated as the average total for each year of operation, and cannot be determined from the average of each item

As can been seen from the results presented in the table, the installation of an 20 MW power plant onsite, fuelled by captured coal seam gas emissions from the mine, would reduce Scope 1 and 2 emissions (emissions within the direct control of the Project and electricity consumed by the Project but generated off-site) each year by approximately 0.26 Mt CO_2-e, or 20%. If the power plant were not installed on the site, the total Scope 1 and 2 GHG emissions would increase by 0.38 Mt CO_2-e or 15% compared to the case presented in Section 6.

9.5.2 Diversion of all captured fugitive emissions to a pipeline for usage offsite

This alternative would replace the flaring of all captured fugitive emissions with a pipeline to an off-site third party power station. This alternative is currently not viable as a Petroleum Lease is required to sell coal seam gas, however has been considered as an alternative in the event that a Petroleum Lease becomes available for the Project in the future. .

Preliminary calculations have been based on the following assumptions:

- the electricity generated by the use of the methane would not offset electricity use of the mine;
- the Scope 1 emissions associated with flaring and power generation are replaced by Scope 3 emissions due to the off-site gas-fired power generation; and
- no allowance has been made for the GHG implications of the pipeline development and operation (e.g. due to land clearing or pipeline compressor stations) .

Table 9-2 compares the proposed Project with the results of the preliminary calculations of this alternative.

Table 9-2 Comparison of Average Annual CO_2-e Emissions of Proposed Project with Pipeline Alternative

Scope	Source	Proposed Project	Pipeline Alternative	Difference
1	Fugitive emissions	182,499	182,499	-
1	Emissions from Flare	41,868	0	-100%
1	Emissions from Power Plant	32,576	0	-100%
1	Diesel combustion	6,238	6,238	-
1	Explosives	408	408	-
	Total Scope 1 [a]	231,114	165,976	-28%
2	Purchased electricity	101,911	152,884	50%
	Total Scope 1 + Scope 2 [a]	333,026	318,860	-4%
3	End-Use for Coking Coal	5,482,476	5,482,476	-
3	End-Use for Thermal Coal	3,588,036	3,588,036	-
3	Electricity Generation and Transmission	14,559	21,841	50%
3	Extraction and processing of Diesel	462	462	-
3	End-Use for Methane	0	78,723	-
	Total Scope 3 [a]	7,951,719	8,027,884	1.0%
	Total Scope 1 + Scope 2 + Scope 3 [a]	8,284,745	8,346,743	0.7%

[a] Totals for each Scope have been calculated as the average total for each year of operation, and cannot be determined from the average of each item

As can been seen from preliminary calculations, the diversion of captured fugitive emission to a pipeline for use at an off-site power station would reduce Scope 1 and 2 emissions (emissions within the direct control of the Project and purchased electricity) each year to approximately 0.16 Mt CO_2-e, or 4%. However, for the full fuel cycle which includes Scope 1, 2 and Scope 3 emissions (indirect greenhouse gas emissions resulting from a company's activities, but occurring from sources not owned or controlled by the company), emissions would be increased to 8.35 Mt CO_2-e, or 0.7%.

9.5.3 Treatment of ventilation air

Various technologies are being examined that would assist in the treatment of mine ventilation air (MVA) and other fugitive losses, which is estimated to account for 25% of the CSG. As methane (CH_4) has a significantly higher global warming potential than CO_2 (see Section 3.3), the additional methane that would be flared and converted to CO_2 and water has a disproportional decrease in the CO_2-e being released to atmosphere, and an overall significantly lower t CO_2-e/tonne raw coal.

Since the efficiency of treatment of mine ventilation air is currently unknown, the GHG reduction using this technology has not been quantified in the context of the whole project emissions. For every additional 5 % fugitive emission from the underground mine captured and flared over the life of the mine, a reduction of 663,588 t CO_2-e is achieved.

9.5.4 Enhanced methane recovery from post-mining (goaf)

Vale is investigating installing technologies that would capture additional methane that would ordinarily be trapped within the underground mine and be difficult to extract. The ventilation system flushes air and methane in operational areas. An enhanced methane recovery system would target areas that are no longer operational (goaf), and where methane tends to accumulate. While this system would not reduce fugitive emissions from ventilation air, it would increase the methane captured from the underground mine for further use (e.g. fuel for a power station). The additional methane that could be captured using this approach cannot be quantified during the project design phase but can be estimated as the Project is developed and operated.

Recent reports suggest that the ECMP is likely to be subject to climate change during the life span of the mine. Climate change therefore has the potential to affect operations at the mine. This section provides an assessment of the risk of climate change impacting the activities of the mine.

10.1 Summary of Predicted Impacts

The following tables summarise the likely effects of climate change in the vicinity of the ECMP, in terms of temperature change, rainfall change, relative humidity, sea surface temperature, wind speed and potential evapotranspiration. The data is sourced from Climate Change in Australia technical report and Climate Change in Queensland technical report. Projections are relative to the period 1980 – 1999 (referred to as the 1990 baseline for convenience). To provide the most accurate result possible, the best estimate results (50th percentile) and the medium emissions scenario from the IPCC Special Report on Emissions Scenarios were used.

Table 10-1 Impacts of Climate Change in Queensland in 2030 and 2050

Season	Temperature Change (ºC)		Rainfall Change (%)		Change in Relative Humidity (%)	
	2030	2050	2030	2050	2030	2050
Annual	+1 to +1.5	+1.5 to +2	-2 to -5	-5 to -10	0.5 to -0.5	-0.5 to -1
Summer	+1 to +1.5	+1.5 to +2	2 to -2	-2 to -5	0.5 to -0.5	0.5 to -0.5
Autumn	+1 to +1.5	+1.5 to +2	-2 to -5	-5 to -10	0.5 to -0.5	0.5 to -0.5
Winter	+0.6 to +1	+1.5 to +2	-5 to -10	-5 to -10	0.5 to -0.5	-0.5 to -1
Spring	+1 to +1.5	+1.5 to +2	-5 to -10	-10 to -20	-0.5 to -1	-0.5 to -1

Season	Wind Speed Change (%)		Change in Potential Evapotranspiration (%)		Sea Surface Temperature Change (ºC)	
Annual	+2 to +5	+2 to +5	+2 to +4	+4 to +8	+0.6 to +1	+1 to +1.5
Summer	+2 to +5	+2 to +5	+2 to +4	+4 to +8		
Autumn	2 to -2	2 to -2	+2 to +4	+4 to +8		
Winter	2 to -2	2 to -2	+4 to +8	+4 to +8		
Spring	+5 to +10	+5 to +10	+2 to +4	+4 to +8		

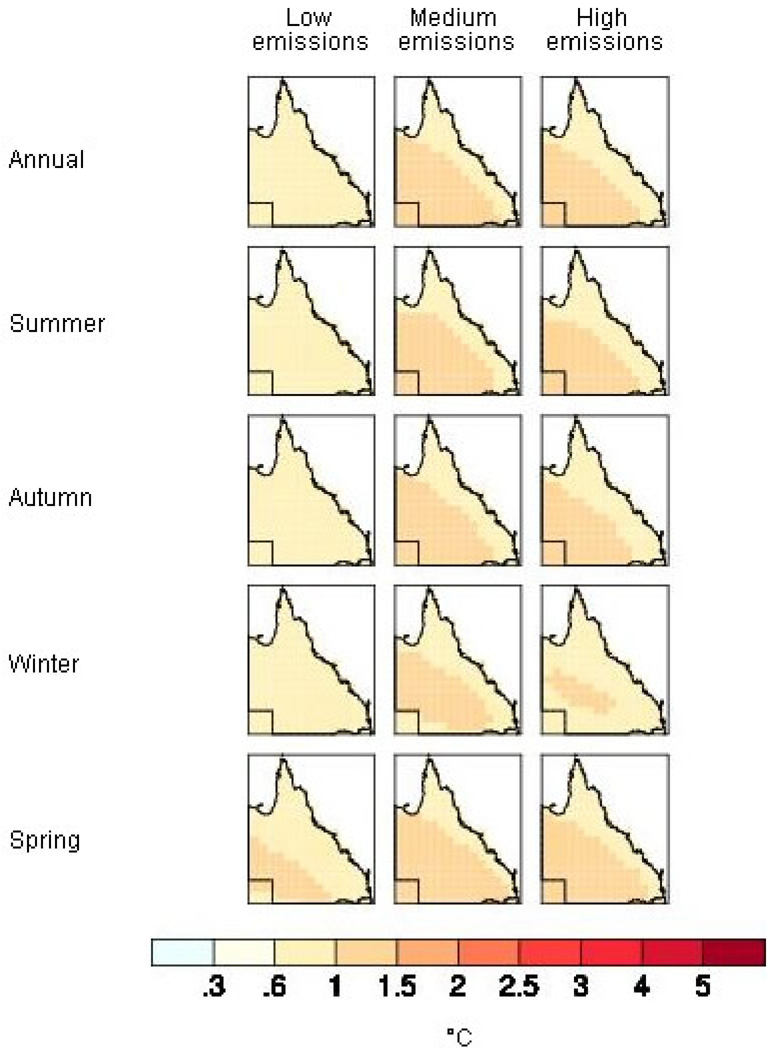


Figure 10-1 Projection in temperature change for Queensland under the low, medium and high GHG emissions scenario - 2030

It can be seen that by 2030 the average annual temperature is expected to increase by between 1 ºC and 1.5 ºC. There is likely to be a corresponding decrease in rainfall of between 2 % and 5 % and wind speed is expected to increase by between 2 % and 5 %.

The changes in temperature are expected to be less pronounced in winter. Changes in rainfall are expected to be more pronounced in winter and spring with a reduction expected in the range of 5 % to 10 %. It is noted that a reduction in rainfall can sometimes lead to a disproportionately greater reduction in water availability.

By 2050 average annual temperature is expected to increase by between 1.5 ºC and 2 ºC. There is likely to be a corresponding decrease in rainfall of between 5 % and 10 %, relative humidity is expected to decrease by up to 1 % and wind speed is expected to increase by between 2 % and 5 %.

The changes in temperature are expected to be experienced equally throughout the year. Changes in rainfall are expected to be more pronounced in spring with a reduction of to 20 %. Wind speed increases are expected to be more pronounced in spring and summer with summer wind speeds expected to increase by up to 10 %.

In summary, during the operating life of the mine it is expected that the local conditions will become hotter, drier and windier. Changes in rainfall and wind speed are expected to be more pronounced in the spring.

The Climate Change in Queensland report notes that a significant proportion of Queensland's agricultural, industrial and mining activity is located in central Queensland and these industries are highly dependant on water resources.

10.2 Risk Assessment

10.2.1 Methodology

The following semi-quantitative risk assessment procedure was used to evaluate the risks as a result of the various potential climate change impacts on mining operations. This approach is consistent with the Australian Standard for Risk Management AS/NZS 4360:2004. The key steps in undertaking the risk assessment involved:

- Identification of the potential climatic impacts on mining operation;
- Analysis of the risks in terms of consequence and likelihood; and
- Evaluate risks, including risk ranking to identify priorities for their management.

To assist in the process of assigning levels of consequence and likelihood, the following measures were used.

Table 10-2 Measures of Likelihood

Level	Descriptor	Description
1	Rare	Occurs only in exceptional circumstances
2	Unlikely	Could occur but not expected
3	Possible	Could occur
4	Likely	Will probably occur in most circumstances
5	Almost Certain	Is expected to occur in most circumstances

Table 10-3 Measures of Consequence

Level	Descriptor	Environmental (Env) Impact	Mine Site Functionality	Financial (per event/per year)
1	Insignificant	Env consequence weeks	No loss of use	<$50,000
2	Minor	Env consequence <12 months	Short terms loss of use (all/part) <1 week	$50,000 to $500,000
3	Moderate	Env consequence 1-2 years	Loss of use (all/part) 1 wk to 1 month	$500,000 to $1 million
4	Major	Env consequence 2-5 years	Loss of use (all/part) 1 month to 1 year	$1 million to $10 million
5	Catastrophic	Env consequence >5 years	Loss of use (all/part) > 1 year	>$10 million

The following risk assessment matrix was used to determine the level of risk based on likelihood and consequence scores. Scenarios with a combined score of 10 or greater are considered to pose a high level of risk. Scenarios with a combined score of between five and eight are considered to pose a medium level of risk. Scenarios with a combined score of less than five are considered to pose a low level of risk.

Table 10-4 Risk Matrix

Likelihood	Consequence				
	1 (Insignificant)	2 (Minor)	3 (Moderate)	4 (Major)	5 (Catastrophic)
5 (Almost Certain)	5	10	15	20	25
4 (Likely)	4	8	12	16	20
3 (Moderate)	3	6	9	12	15
2(Unlikely)	2	4	6	8	10
1 (Rare)	1	2	3	4	5

10.2.2 Results

The risks scenarios were identified on the basis of the authors' experience of mining operations, together with consultation with URS mining specialists. The results of the risk assessment are presented in Table 10-5 below.

Table 10-5 Risk Assessment of the potential impacts of climate change on mine operations

Risk Scenario	Likelihood	Severity	Risk
Reduced process water availability due to decreased rainfall and increased evapotranspiration.	Likely 4	Moderate 3	High 12
Decrease in soil moisture, increased winds and reduced availability of water which increases generation of dust and reduces ability to manage dust.	Likely 4	Moderate 3	High 12
Increased soil erosion due to decrease in soil moisture and increased rainfall intensity (including access tracks).	Likely 4	Moderate 3	High 12
Increased flood risk due to increased rainfall intensity (including box cut area).	Moderate 3	Major 4	High 12
Health impacts on mine site staff from increased temperatures (e.g., heat stress).	Moderate 3	Moderate 3	Medium 9
Unsuccessful rehabilitation planting due to reduced rainfall and more severe storm events.	Moderate 3	Moderate 3	Medium 9
Increased slope failure due to decreased soil moisture and increased rainfall intensity.	Unlikely 2	Major 4	Medium 8
Decrease in efficiency of equipment due to increased temperature resulting in increased operation costs.	Likely 4	Minor 2	Medium 8
Increased maintenance costs for infrastructure due to more severe storm events.	Moderate 3	Minor 2	Medium 6

Risk Scenario	Likelihood	Severity	Risk
Increased bushfire events due to increased temperatures and evapotranspiration potential.	Unlikely 2	Moderate 3	Medium 6
Failure/overtopping of tailings dams.	Rare 1	Catastrophic 5	Medium 5
Community/workforce isolation due to higher risks of flooding events.	Rare 1	Minor 2	Low 2

10.3 Risk Management Measures

The following risk management measures have been adopted by the Project to address the High and Medium Risk scenarios.

High Risk Impacts

- Increase water use efficiency
  - Use the minimum volume of water necessary in the process circuit.
  - Recycle waters in the process circuit or for other uses, such as dust suppression, as much as possible.
  - Segregate water by quality or source.
- Increase flood immunity
  - Apply appropriate risk assessment methods in the sizing and design of storage dams.
  - Protect the mine workings and infrastructure from floodwater inundation.
- Manage soil erosion (including subsided land)
  - Limit the extent of site disturbance.
  - Undertake rehabilitation, including earthworks, drainage and revegetation, progressively for the ECMP.

Medium Risk Impacts

- Avoid heat stress
  - Develop and implement a health and safety management system that will ensure that the safety and occupational health performance of the project meets Vale policy and objectives. The health and safety management system will include:
    - Clear identification of potential health and safety hazards.
    - Risk assessment resulting from the hazards identified.
    - Control measures that prevent or minimise the level of the risk.
    - Procedures for monitoring, review and corrective actions.
- Manage rehabilitation success rates

- Monitor rehabilitated areas on a regular basis to ensure that original objectives are achieved. Monitoring will include regular inspections for soil erosion, rehabilitation success, weed infestation and integrity of water diversion drains, waterways and sediment control structures.

- Ensure slope stability
  - Ensure no less than 75 % of the area has slopes <10 °. Where the slopes are steeper, utilise additional water management structures (as required).
- Maintain equipment efficiency
  - Regularly maintain and service all equipment as per the technical specifications.
- Avoid impact to infrastructure due to severe storm events
  - Apply appropriate risk assessment methods in the sizing and design of storage dams.
  - Install an early detection weather monitoring system where early notification of severe storm events are provided to the ECMP.
- Increase immunity to bushfires
  - Maintain an absence of large stands of trees and provision of a dedicated buffer of 50-100 m around the mine infrastructure area.
  - Staff are to complete fire safety training during induction and thereafter on an annual basis. Water points will be located within the surface infrastructure area and comprehensive fire prevention and suppression system will be in place. The ECMP will have dedicated equipment and water supply on-site for fire-fighting and there will be ongoing communication with adjacent landowners regarding fire breaks and ongoing maintenance programs to minimise bushfire risk.
- Avoid overtopping of tailings dams
  - Design tailings dams to include adequate spillway capacity, adequate design storage allowance (DSA), and operation within mandatory reporting levels (MRL).

References

Section 11

Australian Government (2007), *Australia's Climate Change Policy*, Department of the Prime Minister and Cabinet.

Australian Government (2008) *Carbon Pollution Reduction Scheme: Australia's low pollution future, White Paper.*

Australian Greenhouse Office (2006), *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Fugitive Fuel Emissions)*.

CSIRO (2007), *Climate Change in Australia*, Technical Report 2007.

Day, S (2008), Spontaneous Combustion in Open Cut Coal Mines; *Australian Coal Research Program Report C17006.*

Department of Climate Change (2008), *Climate Change in Queensland: What the science is telling us*.

Department of Climate Change (2008), *National Greenhouse Accounts (NGA) Factors*.

Garnaut, R. (2008), *The Garnaut Climate Change Review*, Final Report, Cambridge University Press.

GeoGAS Pty Ltd (2008), *Report on Preliminary Gas Reservoir Description Ellensfield Project*. GeoGAS Report No.: 2008-526

Intergovernmental Panel on Climate Change (IPCC) (2000), *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*.

Queensland Government (2007), ClimateSmart 2050. *Queensland climate change strategy 2007: a low carbon future*.

Williams, D (1998), Greenhouse Gas Emissions from Australian Coal Mining, *The Australian Coal Review;* October 1998.

World Business Council for Sustainable Development & World Resources Institute (2004), *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard.*